BEFORE THE STATE OF VERMONT
PUBLIC SERVICE BOARD

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
DOCKET NOS. 6946 & 6988

DIRECT TESTIMONY OF HELMUTH W. SCHULTZ, III AND DONNA DERONNE

ON BEHALF OF THE
VERMONT DEPARTMENT OF PUBLIC SERVICE

October 1, 2004

Summary: Witnesses Schultz and DeRonne review CVPS's filing and rate request, and propose a number of adjustments to the Company's revenue requirements.

***** **CONFIDENTIAL INFORMATION <u>REDACTED</u>** *****

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INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Helmuth W. Schultz, III. I am a Certified Public Accountant, licensed in the State of Michigan, and a Senior Regulatory Analyst in the firm of Larkin & Associates PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

I am Donna DeRonne, a Certified Public Accountant, licensed in the State of Michigan. I am a regulatory consultant in the firm Larkin & Associates PLLC whose address was identified above.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES PLLC.

A. Larkin & Associates PLLC is a Certified Public Accounting and Regulatory Consulting firm that performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). The firm has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous electric, gas, water and wastewater, and telephone utilities.

Q. HAVE YOU PREPARED AN APPENDIX WHICH DESCRIBES YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. We have attached Appendices I and II, which are summaries of our experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. Larkin & Associates PLLC was retained by the Vermont Department of Public Service, Public Advocacy Division ("Department"), to review the rate investigation ordered by the Board in Docket No. 6946 and the rate increase requested by Central Vermont Public Service Corporation ("CVPS") in Docket No. 6988. Accordingly, we are appearing on behalf of the Department.

Organization

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. We will address, in order, the following:

Overall Financial Summary

Rate Base

Adjustments to Operating Income

Q. HAVE YOU REFLECTED THE ADJUSTMENTS OF OTHER WITNESSES FOR THE DEPARTMENT?

A. Yes. Our summary schedules reflect the recommendations of Carole Welch regarding DSM and ACE, David Lamont regarding power costs, J. Randall Woolridge regarding cost of capital, and Michael Majoros regarding depreciation.

Overall Financial Summary

Q. WHAT IS THE COMPANY'S POSITION AS REFLECTED WITHIN ITS FILINGS?

A. The Company utilized a 2003 test year and made adjustments for what it perceived as known and measurable adjustments to determine a revenue requirement for Rate Year 1 and Rate Year 2. Rate Year 1 is the twelve month ending March 31, 2005, and Rate Year 2 is the twelve months ending March 31, 2006. The Company's filing reflects a $6,336,000 (2.4%) revenue deficiency in Rate Year 1 and a $13,165,000 (5.0%) revenue deficiency in Rate Year 2. However, the Company is only requesting rates be revised effective April 1, 2005.

Q. WHAT IS THE DEPARTMENT'S FINDINGS WITH RESPECT TO RATE YEAR 1?

A. The Department has determined that the Rate Year 1 will have an overearnings of $12,247,000 or 4.65%. This overearnings should be refunded to ratepayers. The change from the Company's calculated deficiency to the Department's calculated sufficiency is attributed to errors in the filing, an excessive return on equity, overly aggressive projected increases in Rate Year 1 costs, and ignoring the equitable impact of changes in the operations of the Company.

Q. WHAT IS THE DEPARTMENT'S FINDING WITH RESPECT TO RATE YEAR 2?

A. The Department has determined that Rate Year 2 projections will result in an overearnings of $15,626,000 or 5.93%, and rates should be reduced accordingly. The change from the Company's calculated deficiency to the Department's calculated sufficiency is attributed to the same problems identified in Rate Year 1, plus the Company failed to account for the amortization and depreciation it claimed as costs in Rate Year 1.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. We prepared Exhibit DPS-L&A-1 in support of Rate Year 1 and Exhibit DPS-L&A-2 in support of Rate Year 2. Each of these two exhibits contain 22 schedules in support of our adjustments. Schedule 1 in each exhibit contains our overall recommended revenue sufficiency for the respective rate year. Schedules 2 and 3 of each exhibit provides a summary of the adjustments to cost of service and rate base, respectively. Schedule 4 for each rate year contains the Department's recommended cost of capital, which is sponsored by Department witness J. Randall Woolridge. Schedules 5 through 22 provide supporting calculations for our recommended adjustments to cost of service and rate base.

RATE BASE

Plant

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO PLANT ACCOUNTS?

A. Yes. The Company has requested plant additions for interim period January 1, 2004 through March 31, 2004, Rate Year 1 plant additions, and Rate Year 2 plant additions. While it is known plant expenditures will be made, there remains the questions as to what amount will be expended, what will the expenditure be for, and whether the expenditure will be growth related. For several projects, the Company's requests include project names and project estimates that are best guesses that do not meet the known and measurable requirements. In addition, the Company's requests includes duplicated projects and cancelled projects.

Q. WHAT CONSTITUTES KNOWN AND MEASURABLE?

A. Known and measurable adjustments are those that have a high probability of occurring and are quantifiable with a reasonably high degree of accuracy.

Q. HOW IS IT PROJECTS WITH NAMES AND COST ESTIMATES MAY NOT BE KNOWN AND MEASURABLE?

A. To a large degree, some of the projects in Rate Year 1 and the majority of the projects in Rate Year 2 are just a name and number on a piece of paper. It could be considered a wish list. Some of these projects may never materialize, like the ones that have already been cancelled. Some estimates are based on an employee's estimate without any additional support. This type of rationale for a level of cost is really just a guess and is not considered to be an estimate that is quantifiable with a reasonable degree of accuracy.

Q. WHAT WOULD MAKE A PROJECT KNOWN AND MEASURABLE, IN YOUR JUDGEMENT?

A. Projects that have a work order assigned with a detailed description of the project, cost justification and, in some cases, a cost benefit analysis are projects that would meet the known and measurable standard. The projects with work orders that have some form of documented support for the cost estimate have a higher probability of occurring and have a more reasonable quantification than those projects that have a name and an amount based on an employee estimate. Documentation for a cost estimate is considered to provide a higher level of accurate quantification than simply stating "Experienced staff provided estimate." Also as part of our analysis of the known and measurable items, we requested in DPS 3-60 and again in Field Data Request 8 the actual costs to date for the projects included in the Company's filing. For the Board's convenience, we have attached as Exhibit DPS-L&A-4 a comparison of the Company's requested additions and the cost incurred as of August 31, 2004.

Q. WILL YOU BE RECOMMENDING THE COMPLETE DISALLOWANCE OF THE COSTS THAT ARE JUST ESTIMATES?

A. No. We do recognize that some costs will occur, so taking into consideration the minimal support that was provided, a percentage was disallowed on a majority of the projects not truly known and measurable. We will discuss each of the major plant areas below.

<u>Production</u>

Q. WHAT ADJUSTMENTS ARE YOU RECOMMENDING TO THE PRODUCTION PLANT ADDITIONS?

A. All of the Interim Period and Rate Year 1 projects requested by CVPS, except one, are completed or underway. The costs in Rate Year 1 appear to be on target with the exception that the Fairfax Station Modernization cost projection may be on the high side. Additionally, the project was to result in higher generation capacity with a CVPS estimated benefit of $100,000 annually. It is not clear where, or if, this cost savings was reflected. The one project not started is compliance related and supporting detail was provided for the cost estimate. No adjustment is recommended to the projected production plant additions for Rate Year 1.

The Rate Year 2 additions include five projects; for three of these some cost support has been provided. The Human Machine Interface project requested $195,000, and supporting quotes were provided for $116,800. Review of work orders with contracted work indicated that the Company's internal costs could range from between 12% to 48%, with larger projects being around 20%. The cost projection on this project appears reasonably accurate. The Milton Dam cost estimate of $480,000 is supported by a cost estimate; however, the $81,000 (20%) contingency seems high. Also, the cost savings referenced in the Company's prefiled testimony as justification for the project has not been quantified and included in the filing. The Fairfax Turbine project for $75,000 is supported by a $38,000 estimate and falls on the edge of reasonableness when factoring in internal costs. No cost support was provided for the Glen Station Modernization and Silver Lake Automation projects and based on the projects' late projected in service date, there is also a concern that the projects may have slippage beyond the end of the rate year. We are recommending that the Glen Station and Silver Lake projects be removed from Rate Year 2 plant additions. The adjustment, as shown on Schedule 5, page 1 of 3, of Exhibit DPS-L&A-2 reduces Rate Year 2 Plant in service by $436,539, accumulated depreciation by $2,496, deferred income taxes by $6,978 and depreciation expense by $11,933.

Joint Ownership Plant

Q. ARE YOU RECOMMENDING ANY ADJUSTMENT FOR ADDITIONS TO JOINTLY OWNED PLANT?

A. No adjustment is recommended at this time.

Transmission Substations

Q. ARE YOU RECOMMENDING ANY ADJUSTMENT IN RATE YEAR 1 TO TRANSMISSION SUBSTATIONS PLANT ADDITIONS?

A. No. According to the response to DPS 3-60 the Interim Period and Rate Year 1 additions are either complete or underway. Some areas of concern include the WO32 minor additions. When the substations amounts are combined with the transmission lines amounts, the result is slightly higher than the historical five year average level. Next, Work Orders 6799 and 6805 are purportedly 50% complete with no cost or cost support provided, and the respective work orders indicate that the projects will accommodate growth. Finally, the Bromley Fencing/Grounding Upgrade (WO 6814) appears to be overstated by approximately $35,000. However, on an overall basis, the Rate Year 1 costs appear reasonable.

Q. WHY WAS AN ADJUSTMENT MADE ON SCHEDULE 5, EXHIBIT DPS-L&A-2, TO RATE YEAR 2?

A. Other than the two projects that were identified as being either a certain percentage complete or where a cost was provided, the only support for the remaining project costs that would require a work order is the following statement from the response to DPS 3-60:

> The cost estimates provided for projects that do not have a work order are based on the Company's best engineering judgement of the costs to be incurred to complete the project. These engineering judgments are predicated upon a detailed knowledge of utility practice, the CVPS system and of the costs associated with past projects. These engineering judgements have been made by qualified professionals with years of experience in estimating costs for projects. Some have more than 25 years of experience in providing construction cost estimates. These estimates represent the Company's best representation of what the actual work orders will reflect. Estimates are developed and discussed during the budget development process. Therefore, if a project does not have a work order, there is no further supporting documentation beyond that already provided.

The projects summarized may be needed or desired, but despite the experience and qualifications of those making the estimate, the cost is not known and measurable, and the project itself is still at the "hope to do" stage. There is no documentation or support that the respective projects will occur and/or that the cost is quantifiable with a high degree of accuracy. As stated earlier, project additions will occur, but the projects requested by the Company to be included in rates are not truly known and measurable. If a new project is done in place of one of these requested projects, that new project could be growth related and should be excluded from this rate request. Other than the blanket work order for $125,000, there is no justification to increase plant by the total amount requested. Even though justification of the identified projects was not provided as requested, there is no doubt that some projects initiated in Rate Year 2 will be put into service. Based on the fact that some non-growth projects will occur, it is recommended that the Rate Year 2 minor additions and 50% of the Rate Year 2 estimated plant additions be allowed for recovery. As shown on Exhibit DPS-L&A-2, Schedule 5, page 1 of 3, the Rate Year 2 adjustment reduces plant in service by $388,737, accumulated depreciation by $2,989, deferred income taxes by $5,169 and depreciation expense by $9,893.

Transmission Lines

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO TRANSMISSION LINES PLANT ADDITIONS?

A. No adjustment is being made to Rate Year 1 because all projects are purportedly underway, even though actual cost information was not provided for all of the projects. On a project by project basis, there were a number of variances, but the costs provided to date appears on target on a total basis.

As indicated in the discussion of Transmission Substations, the Rate Year 2 justification does not exist on a per project basis. The statement referenced earlier in the response to DPS 3-60 was also the only support provided for Rate Year 2 Transmission Substation plant additions. None of the projects are truly known and measurable, and only the blanket order additions of $160,000 approaches the requirements of the known and measurable standard. In reviewing the Rate Year 2 costs, there is one obvious concern that Rate Year 1 had $606,385 of additions and Rate Year 2 has $1,665,000 of additions. It would appear that the wish list for Rate Year 2 is very optimistic. Because it is known that costs will occur for non-growth additions, it is recommended that the blanket additions and 25% of the requested project costs be allowed. The 25% recommended allowance is less than the 50% for substations because the Rate Year 2 project list is so large in comparison to Rate Year 1. The 25% brings it more in line with Rate Year 1. The Rate Year 2 adjustment for Transmission Lines shown on Exhibit DPS-L&A-2, Schedule 5, page 1 of 3, is a reduction to plant in service of $353,083, accumulated depreciation of $1,775, deferred income taxes of $5,811 and depreciation expense of $8,499.

Distribution Substation

Q. WHAT RATE YEAR 1 ADJUSTMENT IS REQUIRED TO DISTRIBUTION SUBSTATION ADDITIONS?

A. The Rate Year 1 additions to plant in service is being reduced by $25,846, accumulated depreciation is reduced by $115, deferred income taxes by $450, and depreciation expense by $654 for the Bethel Breaker Replacement and the Weybridge 80 & 81 relay upgrade project. The Bethel Breaker replacement is not scheduled to start in Rate Year 1, and there is no cost justification for the Weybridge 80 & 81 relay upgrade project. The only justification provided for the Weybridge 80 & 81 project cost is the statement from the response to DPS 3-60 referenced earlier in our Transmission Substation discussion. Also, there is a concern that while the North Elm Street Cables and Wadstock Cables are purportedly 50% complete, the Company has not identified any cost being recorded as of August 31, 2004.

Q. ARE YOU ADJUSTING RATE YEAR 2 DISTRIBUTION SUBSTATION PLANT ADDITIONS FOR THE SAME REASON THAT YOU ADJUSTED RATE YEAR 2 TRANSMISSION PLANT ADDITIONS?

A. Yes. The actual projects are not known and the costs projected are neither known or measurable. Again, there is a significant $1.6 million increase from $579,000 in Rate Year 1 to $2,225,000 in Rate Year 2 that is a major a concern. Included in the increased project cost is a portable transformer for $850,000 that is requested for reliability reasons, but there is no assurance that this acquisition will occur. There has been no evidence presented that justifies its need, and the description provided indicates this is a discretionary item. Another project is the $250,000 new spare Substation Transformer that also appears to be a discretionary purchase where it is not known whether it will be acquired, and there is no supporting documentation for the cost. Also included by CVPS is $200,000 for a Breaker Replacement that is simply described as a project for the replacement of old breakers that no longer operate reliably. The description is very broad and there is no supporting documentation for this to be considered as a known and measurable addition.

Q. HOW DID YOU DETERMINE YOUR ADJUSTMENT FOR RATE YEAR 2?

A. As shown on Schedule 5, page 2 of 3, of Exhibit DPS-L&A-2, the three projects discussed above were removed from the Rate Year 2 additions, along with the unsupported Rate Year 1 Weybridge project and 50% of the balance of the Rate Year 2 projects after excluding the blanket additions. The adjustment leaves about the same cost as that requested for Rate Year 1 additions. By disallowing the specific work orders and 50% of the balance of the Rate Year 2 projects, plant is being reduced $1,052,000, accumulated depreciation is reduced $12,125, deferred income taxes is reduced $10,426 and depreciation expense is reduced $28,546.

Distribution Purchases

Q. WHAT COSTS ARE IN THE DISTRIBUTION PURCHASES PLANT ADDITIONS?

A. The bulk of the cost reflected in distribution purchases is blanket work orders for transformers, regulators and meters. The blanket for non-growth related transformers averages $707,000 per year. The average amount actually expended over the last five years was $1,835,802. Using the 50.22% non-growth rate used by the Company in Docket No. 6460, the $707,000 a year appears reasonable.

The average cost reflected for meter blanket work orders is $478,409, which is higher than the $307,466 non-growth-related five-year average calculated using the Docket No. 6460 non-growth rate of 50.22%. The regulators blanket work order is supposedly all non-growth related and has averaged $160,879 over the last five years. The average included by the Company in plant additions is $252,546, a 57% increase over the historical average. The regulator blanket cost requested for the 15 months ending March 31, 2005 is $351,228. This amount is high compared to a projection that $229,144 (($122,210/8) x 15) would be spent extending the August 2004 year-to-date spending level. Because this blanket cost was exceeded by over 50%, an adjustment of 50% of the requested amount should be made. Therefore, the Rate Year 1 and Rate Year 2 plant additions should be reduced by at least 50% for regulators.

Finally, of the individual projects included in distribution purchases, the two meter test equipment purchases are considered discretionary and do not have documentation supporting their inclusion in Rate Year 2. These two projects are recommended for removal.

Q. WHAT ARE THE ADJUSTMENTS TO DISTRIBUTION PURCHASES FOR RATE YEAR 1 AND RATE YEAR 2?

A. As shown on Schedule 5 of Exhibit DPS-L&A-1, the Rate Year 1 plant should be reduced $100,998, accumulated depreciation should be reduced $1,499, deferred income taxes should be reduced $876 and depreciation expense should be reduced $3,727.

As shown on Schedule 5 of Exhibit DPS-L&A-2, page 2 of 3, the Rate Year 2 recommended reductions are $324,154 for plant, $8,737 for accumulated depreciation, $5,219 for deferred income tax and $11,526 for depreciation expense.

Distribution Reconstruction

Q. ARE THE DISTRIBUTION RECONSTRUCTION PROJECT ADDITIONS CONSIDERED REASONABLE?

A. In reviewing historical costs, the amounts requested appear reasonable and within the five year average of historical spending. Consequently, no adjustment is recommended.

Facilities

Q. PLEASE EXPLAIN YOUR RECOMMENDED RATE YEAR 1 ADJUSTMENT TO FACILITIES PLANT ADDITIONS.

A. All of the interim projects and seven of the eighteen Rate Year 1 projects were 100% complete and are considered reasonable. There were seven projects in Rate Year 1 that are without any cost incurred as of August 31, 2004 and where either no work order was assigned or there was no support for the cost estimate of these seven projects, four have been deferred, one cancelled and two remain in the rate year. On Schedule 5, of Rate Year 1, we have reflected an adjustment to reduce plant by $53,929, accumulated depreciation by $314, deferred income taxes by $763 and depreciation expense by $1,444 for the four deferred projects and the one cancelled project.

Q. WERE YOU SATISFIED WITH THE COSTS OF THE PROJECTS THAT WERE LESS THAN 100% COMPLETE?

A. Yes, with one exception. The Middlebury Service Center was only 50% complete, and a request for detail showing how the projected costs were determined was responded to with a general explanation. No detailed calculations justifying the cost were made available.

Q. WERE THERE ANY SUPPORTING DOCUMENTS PROVIDED THAT WOULD MAKE THE RATE YEAR 2 ADDITIONS KNOWN AND MEASURABLE?

A. No. No documentation was provided for the projected Rate Year 2 additions. In fact, the only support provided for the cost estimates are brief statements such as “Known pricing from similar purchase," "Experienced staff provided estimate," "Pricing from catalog," and "estimate of previous year purchases." Not even copies of the similar purchases, the catalog page or the amount of previous purchases were supplied in an attempt to justify the costs. The Rate Year 2 additions are not known and measurable. However, since there will be some expenditures, it is recommended that only 50% of the Company's requested Rate Year 2 cost be disallowed, plus the cost of the disallowed Rate Year 1 additions that were flowed through to Rate Year 2. As shown on Exhibit DPS-L&A-2, Schedule 5, page 2 of 3, the Rate Year 2 reductions are $115,013 for plant, accumulated depreciation of $2,230, deferred income taxes of $2,150 and depreciation expense of $3,240.

Information Systems

Q. ARE THERE ANY ADJUSTMENTS NECESSARY FOR RATE YEAR 1 INFORMATION SYSTEMS PLANT ADDITIONS?

A. Yes. Two of the projects (WO 6706 and WO 6778) have been duplicated in the filing and the duplication needs to be removed. Also, the SAN Expansion for $40,000 is not considered to have met the known and measurable requirement and should be removed. On Schedule 5 of Rate Year 1 the project costs are reduced $119,290 for plant additions, $5,948 for accumulated depreciation, $4,428 for deferred income tax and $13,034 for depreciation expense.

Q. WAS THE JUSTIFICATION FOR RATE YEAR 2 INFORMATION SYSTEM PLANT ADDITIONS SUFFICIENT?

A. The level of support provided was better than that provided for most of the other Rate Year 2 projects. Mr. Monder provided quotes and similar completed work orders in an attempt to justify the costs. Detail was lacking on some of the proposed projects, which left some concern as to the overall reasonableness of the estimates. Also, it must be clear that the identification of the project does not make it truly known that the project will occur.

Q. WERE THERE ANY PROJECTS WITHOUT DOCUMENTED SUPPORT?

A. Yes. For example, it is recommended that the Main Frame project be removed because the cost is not known and measurable and the start date of March 2006 makes it more probable that it will slip from the rate year. Even though some form of support for the cost was provided it is still not truly known and measurable; therefore, it is recommended that 25% of the remaining Rate Year 2 plant additions be removed. On Schedule 5 of Exhibit DPS-L&A-2, page 3 of 3, we have recommended a reduction for Rate Year 2 information system plant of $192,641, a reduction to accumulated depreciation of $23,950, a reduction to deferred income tax of $16,796 and a reduction to depreciation expense of $25,618.

Communications

Q. WHAT ADJUSTMENTS ARE YOU RECOMMENDING BE MADE TO COMMUNICATION PROJECTS IN RATE YEAR 1?

A. The Rate Year 1 reduction to plant is $7,431, accumulated depreciation of $99, deferred income tax of $619 and depreciation expense of $374 is based on two cancelled projects.

The adjustment is shown on Schedule 5 for Rate Year 1.

Q. DID MR. MONDER PROVIDE ANY SUPPORT FOR THE COMMUNICATION ADDITIONS IN RATE YEAR 2?

A. Yes. Mr. Monder provides a quote and some completed work orders as support for the costs of some of the new projected additions. However, approximately 58% of the Rate Year 2 cost was not supported. It is recommended that the $133,033 for the unsupported video conferencing be disallowed and 25% of the remaining Rate Year 2 additions be removed. The result, as shown on Schedule 5 of Rate Year 2, at page 3, is an increase of $381,279 for plant, $11,771 for accumulated depreciation, $52,170 for deferred income tax and $18,770 for depreciation expense.

Q. WHY ARE YOU INCREASING PLANT, ACCUMULATED DEPRECIATION, COMMUNICATIONS DEFERRED INCOME TAX AND DEPRECIATION EXPENSE FOR RATE YEAR 2 PLANT ADDITIONS?

A. The Company's filing and workpapers indicate that it was adding plant in Rate Year 2, but the Company made a mistake in its filing and only added some of the additions. To correct the error, the omitted additions had to be included before our recommended adjustment could be deducted.

Other Plant Adjustments

Q. ARE YOU MAKING ANY OTHER ADJUSTMENTS TO PLANT?

A. Yes. In response to DPS 1-32, the Company indicated that it neglected to make an adjustment and identified adjustments for Rate Year 1 and Rate Year 2 to plant for deferred hydro relicensing costs. The adjustment in Rate Year 1 is reflected on Exhibit DPS-L&A-1, Summary Schedules 2 and 3, and increases plant $29,231, accumulated depreciation $225 and depreciation expense $1,172. The adjustment in Rate Year 2 are reflected on Exhibit DPS-L&A-2, Summary Schedules 2 and 3, and increases plant $1,431,538, accumulated depreciation $15,299 and depreciation expense $51,780.

ACCUMULATED DEPRECIATION

Q. ARE THERE ANY ADJUSTMENTS TO ACCUMULATED DEPRECIATION THAT SHOULD BE MADE?

A. Yes. For each of the plant additions we have recommended for disallowance there is an adjustment to accumulated depreciation. The overall reduction to accumulated depreciation for the disallowances in Rate Year 1 of $7,975 as shown on Schedule 5. The overall reduction of $42,529 for Rate Year 2 is shown on Schedule 5, page 3 of 3. Also, the Rate Year 2 accumulated depreciation is increased $15,299 for the hydro relicensing cost the Company forgot to include in the filing. This is reflected on Exhibit DPS-L&A-2, Schedule 3.

Q. ARE ANY ADDITIONAL ADJUSTMENTS TO ACCUMULATED DEPRECIATION

NEEDED?

A. Yes. Company's filing failed to properly adjust Rate Year 1 and Rate Year 2 accumulated depreciation on the base plant in service as of December 31, 2003.

Q. HOW DID YOU DETERMINE THE COMPANY ERRORS?

A. As shown on Schedule 6, page 1 of 2 for each rate year, the Company's amounts were summarized for the entire period beginning with the 13 months ended December 31, 2003 through the 13 months ended March 31, 2006. On Schedule 6, page 2 of 2, the monthly balances were reflected for accumulated depreciation, based on the filing, from December 31, 2003 through March 31, 2006. When comparing the as filed amounts on page 1 to the properly calculated 13 month averages on page 2, it was evident that the Company understated its accumulated depreciation by $4,015,000 in Rate Year 1 and $20,075,000 in Rate Year 2.

Q. WERE YOU ABLE TO DETERMINE WHAT THE COMPANY DID WRONG?

A. Yes. The Company correctly started with the December 31, 2003 year end balance of $212,699,988, correctly added the average Rate Year 1 base accumulated depreciation of $8,029,814, and then added the net negative change in accumulated depreciation of ($2,376,673) for an average rate year ending March 31, 2005 balance of $218,353,129. What the Company forgot is that with a rate year beginning April 1, 2004 (3 months after December 31, 2003) there was three additional months of depreciation from January 1, 2004 through March 31, 2004. The additional three months, shown on Schedule 6, page 2, lines 3-5, would total $4,014,906. The Company simply failed to include all of the interim depreciation required to be included in the 13 month average for Rate Year 1.

The Rate Year 2 error of $20,075,000 is the $4,015,000 from the three-months ended March 31, 2004, plus the Rate Year 1 depreciation of $16,060,000. For Rate Year 2 the Company again started with the December 31, 2003 balance and added half of Rate Year 2 depreciation and the total of the Rate Year 1 and Rate Year 2 accumulated depreciation on Rate Year 1 and Rate Year 2 plant additions. The Company simply failed to recognize the depreciation on existing plant from January 1, 2004 through March 31, 2005.

The Company's filing for Rate Year 1 must reflect an increase of $4,015,000 to accumulated depreciation that will in effect reduce rate base by $4,015,000. The Rate Year 2 filing must reflect an increase in accumulated depreciation of $20,075,000 that will result in a reduction to rate base of $20,075,000.

Q. DOES THAT COMPLETE YOUR DISCUSSION OF ADJUSTMENTS TO ACCUMULATED DEPRECIATION?

A. No. DPS witness Michael Majoros has recommended a change in depreciation expense of $1,807,268 on the base test year plant. The reduction in depreciation recommended has been reflected in the cost of service recommendation on Schedule 2 for each rate year, and would require a reduction to the average rate year accumulated depreciation. The reduction to accumulated depreciation in Rate Year 1 would be $903,634, or one half of the expense. In Rate Year 2 the reduction would be $2,710,902, or all of the Rate Year 1 depreciation plus one half of the Rate Year 2 expense. These revisions to accumulated depreciation are shown on Schedule 3 for each rate year.

ACCUMULATED DEFERRED INCOME TAX

Q. WHAT ADJUSTMENTS ARE BEING MADE TO ACCUMULATED DEFERRED INCOME TAXES?

A. The adjustments include the deferred taxes associated with the recommended disallowance to plant, as shown on Schedule 5 of Exhibit DPS-L&A-1 for Rate Year 1 and Schedule 5, page 3 of 3 for Rate Year 2. The adjustment reduces deferred income taxes $7,136 and $379 in Rate Year 1 and Rate Year 2, respectively.

Additionally, an adjustment of $2,405,000 is shown on Schedule 7. It is the cumulative affect on deferred taxes of various other adjustments for Rate Year 1. On Schedule 7, the adjustment of $3,988,000 is reflected for the various Rate Year 2 adjustment.

DEFERRED COSTS

Q. WHAT TYPE OF DEFERRED COSTS ARE INCLUDED IN THE COMPANY'S REQUEST FOR RECOVERY?

A. The costs that are included in Rate Years 1 and 2 are DSM/ACE, Docket No. 6270 Independent Power Production (IPP) costs, Docket No. 6330 Retail Choice costs, Vermont

Yankee Fuel Rod Repair costs, Vermont Yankee Incremental Power costs due to the sale of Vermont Yankee, and Incremental Decommissioning costs for Yankee Atomic, Connecticut Yankee and Maine Yankee. In addition, the filing reflects various deferred credits as partial offsets to the deferred costs described above.

Q. HAVE YOU IDENTIFIED ANY ERRORS, CONCERNS, OR PROBLEMS WITH THE AS FILED DEFERRED AMOUNTS?

A. Yes. A major error in the Company's filing is that when it calculated the Rate Year 2 rate base and expense, it forgot Rate Year 1 had occurred. For example, the Docket 5980 DUP DSM costs had a March 31, 2004 balance of $383,797, and the Company proposed to amortize $76,569 during Rate Year 1. According to Rate Year 2's Schedule 7, the March 31, 2005 Docket 5980 DUP DSM balance is $420,865 and the annual amortization is $84,173. You can not begin with $383,797, write-off $76,569 and end up with $420,865. The Company appears to have taken the position that for the rate investigation in Rate Year 1 it is entitled to amortization of the deferred costs in its attempt to show a rate decrease and refund is not warranted. The Company then comes right back in Rate Year 2 and instead of continuing the systematic recovery of those deferrals, it asks for the recovery of the Rate Year 1 amortized amounts again, plus asks for additional carrying costs.

Q. DID THE COMPANY FOLLOW THIS ERRONEOUS APPROACH ON ALL DEFERRED COSTS?

A. The error is consistent with the deferred costs and credits included in rate base. The deferrals flowing through power costs are based on the estimated costs for the respective rate years.

Q. ARE THERE CONCERNS OR PROBLEMS WITH THE BEGINNING AMOUNTS REFLECTED AS RECOVERABLE?

A. Yes. There are costs that should not be allowed to be recovered at all, there are amounts that are not fully justified, and there are amounts that were not properly determined.

Q. WHAT COSTS ARE THERE CONCERNS OR PROBLEMS WITH AND WHAT COSTS ARE CONSIDERED REASONABLE?

A. Schedule 8 of Exhibits DPS-L&A-1 and DPS-L&A-2 summarize the deferrals that are discussed, in order, in this testimony. The deferrals for incremental decommissioning that are reflected in power costs will be discussed under power costs after the costs and credits requested by the Company to be included in rate base. The associated adjustments to amortization expense are reflected on Schedule 15 for each rate year.

Docket 5980 DUP DSM/ACE

Q. IS THERE AN ADJUSTMENT RECOMMENDED FOR THE DSM AND ACE COSTS INCLUDED IN THE FILING?

A. Department witness Carole Welch has evaluated the reasonableness of the requested costs. DPS witness Welch is recommending that all of the amounts associated with the DSM regulatory asset be removed as the Company has already fully recovered these amounts from ratepayers. The removal results in a $76,759 reduction to amortization expense and a $345,417 reduction to rate base in Rate Year 1.

In Rate Year 2, amortization expense and rate base would be reduced by $84,173 and $378,779, respectively. These removals to rate base are reflected in our Schedule 8, page 2, for Rate Year 1 and Rate Year 2. The removal of amortization expense is reflected on Schedule 15 for each rate year.

Q. PLEASE EXPLAIN THE ACE ADJUSTMENT.

A. DPS Witness Carole Welch has recommended several revisions to the amounts added by CVPS to the ACE deferral. The impact of her recommended revisions, along with our revisions to CVPS's amortization and removal of the accumulation of carrying costs after the beginning of Rate Year 1, is presented on Schedule 8, page 3.

As shown on Schedule 8, page 3, the Rate Year 1 ACE costs included in rate base should be reduced $13,054 and the amortization for ACE in Rate Year 1 should be reduced by $18,279 from $91,194 to $72,915. As shown on Schedule 8, page 3 of Exhibit DPS-L&A-2, the Rate Year 2 costs included in rate base are reduced for the Rate Year 1 and Rate Year 2 cost adjustments recommended by Ms. Welch, the Rate Year 1 amortization and the Rate Year 2 amortization, with no additional carrying costs.

Q. WHY ARE THE CARRYING COSTS REMOVED?

A. Once costs are recognized for recovery in rates and in rate base, there are no additional carrying costs. The Company's filing claims the cost in Rate Year 1, so carrying costs should not be calculated and added beyond March 31, 2004.

Q. CONTINUE WITH THE RATE YEAR 2 ADJUSTMENT.

A. The adjustment in Rate Year 2 to rate base is $73,854. The amortization expense should be reduced $57,647 to $52,052.

Docket No. 6270 Independent Power Production

Q. WHAT ADJUSTMENTS ARE YOU RECOMMENDING FOR THE DOCKET NO. 6270 INDEPENDENT POWER PRODUCTION COSTS?

A. In Rate Year 2, the rate base has been adjusted to reflect the Rate Year 1 amortization. The rate base should be reduced $47,268 from $118,169 to $70,901. The amortization expense does not require an adjustment. This adjustment is shown on Rate Year 2 Schedule 8, page 4.

Docket No. 6330 Retail Choice Petition

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING FOR THE DOCKET NO. 6330 RETAIL CHOICE PETITION COSTS?

A. In Rate Year 2 the rate base has been adjusted to reflect the Rate Year 1 amortization. The rate base should be reduced $2,053 from $5,136 to $3,083, as shown on Rate Year 2

Schedule 8, page 5. The amortization expense does not require an adjustment.

Vermont Yankee Fuel Rod Fix

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE DEFERRAL FOR VERMONT YANKEE FUEL ROD FIX?

A. Yes. On July 18, 2002, the Board issued an Order allowing the deferral of the cost associated with the defective fuel rods at Vermont Yankee. The Order stated that the Company could defer the costs, but amortization was to begin January 1, 2003. The Order also stated that if the plant was sold, the costs should be written off. The Company objected to those two requirements and requested reconsideration. On August 6, 2002, the Board revised its Order and deleted the two requirements. The Company's justification for the deferral is that it claims the event was extraordinary due to the outage being of a materially longer duration than the types of outages generally recognized in the forced outage rate, and the outage was incremental to the types of outages recognized in the pro forma adjustments used for retail rate setting purposes. The questions are whether the outage that occurred due to the defective fuel rods is an extraordinary event, whether that event, being extraordinary or not, is an outage not considered to be covered by the Vermont Yankee forced outage rate, and whether the forced outage allowance in rates in 2002 was fully utilized. The 2002 Vermont Yankee financial statements make no reference to any extraordinary event, so it is questionable how CVPS can characterize the event as extraordinary. In addition, the Company was aware of the defects back in January 2002, which raises a concern as to why the repairs were not done until May of 2002. The allowance of costs in rates is questionable, the costs were incurred prior to the recognition of the sale, and the purchaser was, or should have been, aware of the added cost and, therefore, accepted responsibility for the cost.

Additionally, Department witness Dave Lamont has recommended a reduction to the deferral related to plant performance. He reduces the deferral by $629,023.

On Schedule 8, page 6, we have reflected the necessary reductions to rate base for the VY fuel rod repair deferral. As shown on the schedules, rate base should be reduced by $524,186 and $1,627,767 in Rate year 1 and 2, respectively. As shown on Schedule 15 for each rate year, amortization expense should be reduced by $$209,669 and $311,806, respectively.

<u>Vermont Yankee Incremental Costs Due to Sale</u>

Q. IS AN ADJUSTMENT REQUIRED FOR THE VERMONT YANKEE INCREMENTAL COST DUE TO SALE DEFERRAL?

A. Yes. Just like the other deferrals, the Company included some of the cost twice, as well as including unjustified carrying charges. As shown on Schedule 8, page 7, the Rate Year 2 rate base has been reduced $2,463,856 to reflect Rate Year 1 amortization and remove Rate Year 1 carrying charges. Rate Year 2 rate base should be $2,977,204. Amortization expense in Rate Year 2 should be reduced $191,624 from $2,176,424 to $1,984,800, as shown on Exhibit DPS-L&A-2, Schedule 15.

Vermont Yankee Replacement Energy/06-04 Outage

Q. IS THERE AN ADJUSTMENT FOR THE VERMONT YANKEE REPLACEMENT ENERGY COSTS?

A. Yes. As explained by DPS witness David Lamont, the cost being sought for recovery are not appropriate for recovery from ratepayers. The costs have been deemed to be associated with the uprate and should be recoverable from Entergy. As shown on Exhibit DPS-L&A-2, Schedule 8, page 1, rate base should be reduced $744,254 in Rate Year 2 and amortization expense should be reduced $297,702 in Rate Year 2 as shown on Schedule 15. No costs are reflected in Rate Year 1, so no adjustments are required in Rate Year 1 deferrals.

Yankee Atomic Incremental Decommissioning

Q. WHY IS AN ADJUSTMENT REQUIRED FOR YANKEE ATOMIC INCREMENTAL DECOMMISSIONING?

A. The costs sought for recovery in Rate Year 1 are the costs paid through March 31, 2004. While the payment of the costs would generally make the costs eligible for recovery, some of the costs are also subject to recovery from the Department of Energy (DOE). In addition, the Company has not received authorization from the Board to defer the costs. Assuming that the costs are deemed recoverable, there is no rate base adjustment in Rate Year 1, and no adjustment to amortization expense in Rate Year 1. However, as shown on

Schedule 8, page 8, Rate Year 2 rate base should be reduced $2,112,601 from $2,889,194 to $776,593. Amortization expense in Rate Year 2 should be reduced $637,949 from $1,155,678 to $517,729, as shown on Schedule 15. The rate base costs in Rate Year 2 are overstated because the Company failed to recognize Rate Year 1 amortization. Even though the Company reflects the cost paid in Rate Year 1 in purchase power expense, it nonetheless added the payments to the deferred balance. The Company has taken a deduction in Rate Year 1 for payment of the cost and then included that same cost in the deferral for recovery a second time. There is no justification for double recovery of these costs.

<u>Connecticut Yankee Incremental Decommissioning</u>

Q. WHY DID YOU REMOVE ALMOST ALL OF THE RATE YEAR 2 RATE BASE AMOUNT AND AMORTIZATION FOR CONNECTICUT YANKEE INCREMENTAL DECOMMISSIONING?

A. The Company seems to be trying for double recovery. During Rate Year 1, the Company projected payments of $1,310,268 in power costs. It then claimed deferral of $458,684 for a portion of the same amounts expensed. The deferred amount is based on the Rate Year 1 payments less the $815,000 "in rates." The amount expensed in Rate Year 1 cannot be used in determining a deferral for future recovery. The only amount that should be allowed to be deferred is the difference between the January 2004 to March 2004 payments of $219,793 and the $203,750 allowed in rates from Docket No. 6460. As shown on Schedule 8, page 9, Rate Year 2 rate base should be reduced $368,868 from

$382,237 to $13,369. Amortization expense should be reduced $147,528 from $152,895 to $5,347, as shown on Schedule 15 for Rate Year 2.

Docket 6062 VEPPI Cost Mitigation Rebate and Docket 6270 Benefit

Q. IS THERE AN ADJUSTMENT TO THE VEPPI COST MITIGATION DEFERRAL?

A. Yes. The Rate Year 2 rate base and amortization should be adjusted to remove Rate Year 1 amortization and Rate Year 1 carrying cost. However, without sufficient detail for the cost change during Rate Year 2, and since the accounting may not be able to terminate as of March 31, 2004, we have only adjusted for the amortization from Rate Year 1. As shown on Schedule 8, page 10, Rate Year 2 rate base should be increased $116,705 by reducing the credit from $820,205 to $703,500. The amortization credit for Rate Year 2 should be reduced $140,918 from $328,082 to $187,164 (12 x $15,597).

Docket 6460 Millstone Decommissioning

Q. IS A SIMILAR ADJUSTMENT REQUIRED FOR THE MILLSTONE DECOMMISSIONING COSTS REFLECTED IN RATES?

A. No. As shown on Schedule 8, page 11, Rate Year 2 rate base will be increased $404,937 to reflect the reduction in the credit balance from $596,268 to $191,331. The amortization credit will be reduced $110,952 from $238,507 to $127,555. This change is because the Company removed the expense from cost of service in their Adjustment 32, so it would be inappropriate to give ratepayers credit in Rate Year 1 for an expense no longer being charged to them.

Docket 5800 Brockway Mills Refund

Q. WILL THE BROCKWAY MILLS REFUND ALSO BE ADJUSTED IN A SIMILAR MANNER?

A. Yes, except there is no adjustment for additional revenue included in current rates. With the removal of Rate Year 1 amortization and carrying costs the Rate Year 2 rate base credit is reduced $66,305 from $146,837 to $80,532. Likewise, the amortization credit is reduced $5,047 from $58,735 to $53,688.

Docket 6270 Non Petitioning Utilities Cost Reimbursement

Q. DOES THE DEFERRED CREDIT FOR NON PETITIONING UTILITIES COST REIMBURSEMENT ALSO GET ADJUSTED FOR AMORTIZATION AND CARRYING COST?

A. No. Only the Rate Year 1 amortization needs to be reflected because the Company did not adjust Rate Year 2 for carrying costs. Schedule 8, page 13, shows the Rate Year 2 rate base credit is reduced $106,396 from $265,991 to $159,595. The amortization credit in Rate Year 2 does not require an adjustment.

Earnings Cap

Q. IS AN ADJUSTMENT REQUIRED FOR THE EARNINGS CAP CREDIT?

A. Yes. Similar to the other deferrals, the Rate Year 1 amortization and Rate Year 1 carrying cost must be removed from the Rate Year 2 rate base amount. However, there is an additional adjustment to the balance as of March 31, 2004. The overearnings as of March

31, 2004 is understated by at least $4,306,000.

Q. HOW COULD THE OVEREARNINGS BE UNDERSTATED?

A. The Company's overearnings calculation was done by taking the CVPS consolidated net income and common stock equity and reducing them by the net income and common stock equity, respectively, of its non-regulated subsidiaries and its New Hampshire utility subsidiary. The resulting net income is compared to the resulting common stock equity to arrive at the purported Vermont jurisdictional electric utility operations return on equity. This methodology is not consistent with rate making principles where the return on equity is factored into the capital structure and an authorized rate of return is determined. The Company's methodology does not match the capital structure with the rate base allowed. Because of that mismatch, the Company's methodology assumes different facts from those assumed when rates were set. For example, the average test year 2003 adjusted rate base is $243,245,000 (Company Schedule 3). Based on the Company's calculation in Informal Response No. 6, the average common equity for 2003 was $156,131,085. This results in equity of $156,131,085, plus the average debt of $132,000,000 and preferred stock of $18,053,800, for a total capital investment of $306,184,855. The Company's method does not synchronize the rate base and the capital structure.

Q. HOW SHOULD THE OVEREARNINGS BE CALCULATED?

A. The best way to determine if there is an overearnings is to calculate the revenue requirement for the year of determination using actual information in the same format that is used for setting rates. The only adjustments to actual amounts should be for standard accepted regulatory adjustments or adjustments to remove costs that are not to be included in regulatory cost of service. What is interesting is the Company used the equity method for determining whether there was a 2001-2003 overearnings, but for Rate Year 1 the Company used the standard Vermont ratemaking methodology to show that they will not overearn in the period ended March 31, 2005. The ultimate answer sought in both scenarios is whether CVPS will earn in excess of an allowed return.

Q. DID YOU USE THE STANDARD VERMONT RATEMAKING CALCULATION TO DETERMINE IF CVPS OVEREARNED DURING EACH OF THE YEARS 2001-2003?

A. That method was used for 2003, as shown on Schedule 9. The only adjustments made to the Company's 2003 test year rate base amounts were the addition of capital expense, the removal of construction work in progress and reflecting a credit for other current liabilities. The cost of service is adjusted to remove the management incentive compensation agreed to be removed from rates by the Company in 2002 in Docket No. 6677. The result for 2003 is an overearnings of $6,845,000 compared to the Company's calculated $2,539,000. The calculation, as shown, does not adjust the 2003 revenue from Ultimate Consumers for the $777,387 of unbilled revenue excluded by the Company.

The years 2002 and 2001 were not recalculated because of the information needed to make the calculation was not readily available and was not provided by the Company as requested. CVPS should be required to recalculate its overearnings for those years using the methodology described above.

Q. WHAT IS THE ANNUAL OVEREARNINGS THAT SHOULD BE RECOGNIZED IN THIS PROCEEDING?

A. As shown on Exhibit DPS-L&A-1, Schedule 8, page 14, the accumulated overearnings, as of December 31, 2003, is $7,600,038. The $7,600,038 amortized over three years results in an annual credit to cost of service of $2,533,346. The Rate Year 1 credit to rate base must be increased $3,588,334 from $2,745,032 to $6,333,366. The Rate Year 1 credit to expense should be increased $1,435,333 from $1,098,013 to $2,533,346. The Rate Year 2 credit to rate base should be increased by $796,926 to $3,800,020 from $3,003,094. The net increase reflects the corrected overearnings less Rate Year 1 amortization, less Rate Year 1 carrying cost. The credit to expense in Rate Year 2 is increased $1,332,108 from $1,201,238 to $2,533,346.

POWER COSTS

Q. ARE THERE ANY ADJUSTMENTS TO POWER COSTS?

A. Mr. David Lamont is addressing power cost in general, with the exception of the accounting for the Maine Yankee, Connecticut Yankee and Yankee Atomic Incremental Decommissioning costs. Mr. Lamont has recommended that the net purchase power cost be increased by $793,000 in Rate Year 1 and reduced by $4,296,000 in Rate Year 2, excluding the incremental decommissioning referred to earlier. His recommended power cost adjustments are reflected on Schedule 2 for each of the respective rate years.

Q. ARE THERE CONCERNS WITH THE REQUESTED INCREMENTAL DECOMMISSIONING COSTS?

A. Yes. First, the costs are recorded in purchase power and they are not purchase power costs. The FERC definition of cost to be included in purchase power refers to the purchase of electricity for resale and does not make any reference to incremental decommissioning cost. This is especially important because the cost that the Company is requesting ratepayers to pay is based on estimates and does not reflect any credits for claims that the respective Yankee units have filed against the DOE and Bechtel Corporation. These costs, which are being collected from ratepayers, are also subject to recovery from the DOE, and some are the subject of litigation with Bechtel Corporation.

Additionally, beyond the Bechtel litigation, there has been a prudence question raised regarding Connecticut Yankee's decommissioning. There is also a concern that the costs reflected by the Company in the filing are front loaded and could result in over-recovery without recourse for ratepayers.

Q. WHY ARE SOME OF THE COSTS SUBJECT TO RECOVERY FROM THE DOE?

A. Yankee Atomic, Maine Yankee and Connecticut Yankee have filed litigation charging that the Federal government breached contracts it entered into with each of the respective companies under the Nuclear Waste Policy Act of 1982. The claims are for additional costs incurred for decommissioning of the respective plants due to the government failure to remove the spent nuclear fuel. The amount claimed for Yankee Atomic, Maine Yankee and Connecticut Yankee is $191 million, $160 million and $197 million, respectively. On August 9, 2004, Exelon announced it had reached an agreement with the Justice Department and DOE to settle its claim for costs due to the DOE's failure to begin acceptance of spent nuclear fuel for disposal in 1998. The agreement provided for payment of $80 million of costs already incurred, and annual payments thereafter, until the waste acceptance actually takes place. The recovery of costs must be monitored closely to provide assurance that cost paid for by ratepayers are rightfully credited to them, and to minimize future payments by ratepayers.

Q. WHAT IS YOUR CONCERN REGARDING THE COSTS BEING FRONT LOADED?

A. The Company's filing reflects the costs estimated to be paid in Rate Year 1 and Rate Year 2. Rate Year 2 includes only three months of cost from 2006, the year payments are projected to start a significant decline. If rates are set using the Rate Year 2 amount, the Company will be significantly overpaid in each of the subsequent years.

Q. COULD YOU PROVIDE AN EXAMPLE OF THE POTENTIAL OVERPAYMENT?

A. Yes. On Schedule 10, pages 1-4, of Exhibit DPS-L&A-1, the various requests have been summarized to show the source document detail, the amounts reflected in the filing, the Company's filing assuming Rate Year 2's request is in effect for exactly three years, and the potential recovery based on the filing.

For Yankee Atomic the sum of costs paid as of March 31, 2004 and the remaining deferral through 2010 is $7,188,353, as shown on page 2 of Schedule 10. If Rate Year 1 is allowed as requested and Rate Year 2 is in effect for three years, the Company would recover $10,548,492, or $3,360,139 more than it would be entitled to. If rates continued out to the end of the recovery period the Company has the potential of over recovering in excess of $10 million or $17,985,818.

The potential for over-recovery also exists for Connecticut Yankee and Maine Yankee. In each scenario, the Company will over-recover in the two years following Rate Year 2. It is not appropriate for ratepayers to provide the amounts requested, especially given the fact that the litigation could significantly impact the amount of the future payments that are the Company's basis for its request. The potential over-recovery amounts are shown on pages 3 and 4 for Connecticut Yankee and Maine Yankee, respectively.

Q. HOW DO YOU PROPOSE THIS PROBLEM BE RECTIFIED?

A. The Company has already recorded an estimated liability and deferred debit for the expected obligation through 2010. The Company will adjust the balance as more up to date information is received and hopefully when the litigation is resolved. The deferrals should be a regulatory asset and liability amortized on a straight line basis over the period April 1, 2004 through December 31, 2010 (81 months). The costs do not belong in power costs. Any changes to the amounts based on actual vs estimated and any recovery by the respective Yankee units passed on to the owners should be reported to the Board on a quarterly basis. The amounts in question are significant and subject to great volatility and because of those facts they deserve very close scrutiny. Without proper monitoring, ratepayers and the Company could be significantly harmed. It is in the best interest of all concerned that these costs be monitored.

Q. WHAT ADJUSTMENTS ARE REQUIRED TO IMPLEMENT YOUR RECOMMENDATION?

A. Power cost should be reduced $4,500,585 and $5,302,437 in Rate Year 1 and Rate Year 2, respectively. Additionally, an adjustment to reflect the levelized amortization of $3,781,759 should be made in each of the rate years. This results in a net reduction to cost of service of $718,826 and $1,520,678 in Rate Year 1 and Rate Year 2, respectively. These adjustments are reflected on Exhibit DPS-L&A-1, Schedule 10, page 1 of 4 and Exhibit DPS-L&A-2, Schedule 10.

UNBILLED REVENUES

Q. DID THE COMPANY INCLUDE UNBILLED REVENUES IN THE REVENUE REQUIREMENT CALCULATION?

A. No, it did not. In determining the amount of its purported revenue deficiencies in Schedules 1 for rate years 1 and 2, the Company subtracted the actual revenues from ultimate customers of $262,706,000. However, this amount only included billed revenues and did not include the change in unbilled revenues occurring between the year end 2002 and the year end 2003 balance.

Q. SHOULD THE CHANGE IN THE UNBILLED REVENUES BALANCE BE INCLUDED IN DETERMINING THE AMOUNT OF REVENUE DEFICIENCY/SUFFICIENCY?

A. Absolutely. When determining the amount of revenue deficiency or sufficiency, it is important to base the amount on the amount of revenue actually earned during the year. Consequently, the net change in the balance of unbilled revenues as the beginning of the test year and unbilled revenues at the end of the test year must be factored in. To do otherwise would result in the actual test year level of revenues not being reflected and a distortion of the matching of the revenues with the costs incurred to generate those revenues.

Q. ARE THERE ANY OBVIOUS PROBLEMS WITH THE MATCHING OF REVENUES WITH THE COSTS INCURRED TO GENERATE THOSE REVENUES IN THE FILING?

A. Yes. Test year power costs are based on the 2003 level. No adjustment was made by the Company to remove the power costs associated with the additional revenue that was earned, but remained in the unbilled revenues account. In other words, the power costs incurred to generate the increase in the net unbilled revenues is included in the test year, but the associated revenue is not. This causes a distortion of the relationship of the revenues in the filing and the costs incurred to generate those revenues.

By not including the change in unbilled revenues, you also are not including the full impact of customer growth that occurred during the rate year. One of the reasons that the balance of unbilled revenues may increase from the beginning of the year to the end of the year is due to growth in the overall customer level, resulting in a higher balance of unbilled revenues as time progresses. The investment associated with serving the higher customer level would be included in the test year, yet the full impact of the growth in customers would not be reflected in revenues if an adjustment is not made for the change in unbilled revenues.

Q. WHAT ADJUSTMENT NEEDS TO BE MADE TO REFLECT THE UNBILLED REVENUES?

A. In response to DPS 5-22, the Company indicated that the difference between the Accrued Utility Revenues at December 31, 2002 and the Accrued Utility Revenues balance at December 31, 2003 is $777,387, and this is the amount of unbilled revenues that has been excluded from the filing. Thus, Rate Year 1 and Rate Year 2 revenues should both be increased by $777,387 in determining the amount of revenue sufficiency in each of those rate periods. These adjustments to increase revenues by $777,387 are reflected on our Schedule 2 of each of the rate years.

PAYROLL

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO PAYROLL EXPENSE?

A. Yes. Payroll expense should be reduced $748,685 in Rate Year 1 and $1,153,232 in Rate Year 2. The adjustment reflects a reduction to incentive compensation and a reduction to the Company's adjustment for employee additions and is calculated on Schedule 11 for each of the rate years.

Q. COULD YOU EXPLAIN THE COMPANY'S PAYROLL EXPENSE CALCULATION?

A. Yes. The Company calculation for each rate year starts with an annualized base payroll of $27,773,243 for 514 employees as of December 31, 2003. That base payroll amount was multiplied by an O&M expense factor of 74.85%, resulting in O&M payroll expense of $20,788,272. Test year bonuses and overtime are added to the expense, resulting in a pro forma expense of $22,929,723. The actual calculation of the respective rate year payroll expense essentially begins, here with the application of the cumulative increases in pay, the respective annual incentive compensation, and the cumulative projected net increase associated with the addition of employees.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE PAY INCREASES PROJECTED BY THE COMPANY?

A. No. However, the Board should take notice that the cumulative affect of the respective increases are on the high side of reasonable. The January 2004 executive increase was 8%, and the effective union increase as of January 2004 was 4.09% plus a 1.6% increase for progression, resulting an annual increase of approximately 5.69%.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING FOR INCENTIVE COMPENSATION?

A. The Company has reflected incentive compensation of $887,380 and $1,187,760 for Rate Year 1 and Rate Year 2, respectively. The incentive compensation should be reduced $310,583 to $576,797 in Rate Year 1 and a reduced $586,702 from $1,187,760 to $601,058 in Rate Year 2.

Q. WHY HAVE YOU ADJUSTED THE INCENTIVE COMPENSATION EXPENSE INCLUDED IN PAYROLL?

A. The testimony of Joan Gamble states that there are three Company measures for 2004 for the Employee Incentive Plan (EIP). The financial portion consisting of EPS and cash flow is 50% of the weighting and the customer/employee portion is 50%. The earning per share is 30% of the weighting. Based on CVPS Exhibit JFG-14 the earnings per share requires a target earnings per share of $1.24. According to Informal Data Request No. 6, the regulated earnings per share for 2002 and 2003 was $1.49 and $1.57, respectively. Setting a target below the past two years achievements does not provide an incentive to improve. It only reflects a desire to pay added compensation without improving operations. Some of the Company-wide goals depicted on CVPS Exhibit JFG-14 do raise the bar and do appear appropriate.

The fourteen different teams identified in CVPS Exhibit JFG-14 have goals that also are of concern. While some include performance where the bar was not raised, the major concern is the level of discretionary determination. The discretionary determination ranges from 12.5% to 85% of the different teams' goals. The average is 44%. A majority of the goals are customer service, cost control and employee related. However, there is the "Enhance Shareholder Value" objective which includes preventing detrimental legislation and regulation, not exactly a ratepayer-oriented objective. The discretionary determinations are subjective, and the poor Company morale could influence the determination.

Q. HOW DID YOU DETERMINE THE ADJUSTMENT TO INCENTIVE COMPENSATION?

A. In Rate Year 1, the weighted EIP percentage is 3.87% based on a 10% rate for Key Contributors and a 6% rate for Office & Clerical and Exempt employees. As a guide, the Company goals set are deficient by 30% (the earnings per share portion), 20% is questionable (the cash flow portion), and with 20% being discretionary, it is recommended that 35%, (or one half the identified areas) be disallowed. The Rate Year 1 incentive compensation adjustment is a reduction of $310,583, or 35% of the Company amount of $887,380. While the plan setup and goals are headed in the right direction, the full amount should not be allowed until it can be shown that the bar has been raised, there is an adequate, and quantifiable cost benefit to ratepayers, and there is evidence that the plan really works in providing motivation for employees to improve operations.

Q. IS IT NECESSARY TO RAISE THE BAR?

A. Yes. Just because a goal has been achieved does not mean that it should lock in an incentive payment for life. As long as there is room for improvement, the bar should be continually raised. If the maximum possible level of performance has been achieved, then the goal must be replaced with a new area for improvement.

Q. WHY SHOULD A QUANTIFIABLE COST BENEFIT BE REQUIRED?

A. It is good to establish an EIP that focuses on customer satisfaction, employee satisfaction and compliance, but the fact remains that the EIP is extra compensation that is an added cost of operations and it is good business practice to justify added costs by reducing other costs. Capital projects will require cost benefit analysis to justify the undertaking of the project. The providing of EIP, which is compensation over and above the wages being paid to employees for an expected level of safe and reliable service, should also be justified with a cost benefit.

Q. WHY SHOULD THE EIP MOTIVATE EMPLOYEES?

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Q. xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxx?

A. xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx

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END CONFIDENTIAL

Q. IF THE JUSTIFICATION FOR THE COSTS DOES NOT EXIST, WHY ARE YOU ALLOWING A PORTION OF THE COSTS?

A. The employee perception is only a piece of the equation. As indicated, there are goals that improve service, there is some cost benefit identified by the Company from cost reductions, and there are some employees that are convinced the incentive plan provides motivation. It does appear that the EIP is providing some benefit, so credit must be given where credit is due. The EIP simply has not developed sufficiently to justify the full cost of this extra compensation plan.

Q. DID YOU REDUCE RATE YEAR 2 BY THE SAME 35%?

A. The 35% adjustment was made after first reducing the Rate Year 2 expense for an amount that is definitely not known and measurable and that is considered excessive.

Q. WHAT IS THE ADJUSTMENT FOR THE EXCESSIVE AMOUNT AND WHY IS IT NOT KNOWN AND MEASURABLE?

BEGIN CONFIDENTIAL

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Q. WHAT EIP RATE ARE YOU RECOMMENDING?

A. The EIP rate for Rate Year 2 should be the same 2.52% that is recommended for Rate Year 1. The only difference is that in Rate Year 2 the wage increase from Rate Year 1 was added to the base before calculating the incentive amount. This appears to be an oversight by the Company in determining the Rate Year 2 base.

Q. WHY ARE YOU REDUCING THE COMPANY'S ADJUSTMENT FOR EMPLOYEE ADDITIONS?

A. The Company's adjustment is not known and measurable, it lacks sufficient justification, and there is an error in the Company's filing.

Q. WHAT IS NOT KNOWN AND MEASURABLE ABOUT THE ADJUSTMENT?

A. The Company projects a net addition of 34.5 Full Time Equivalents (FTEs) in Rate Year 1 and seven more in Rate Year 2, for a total of 41.5 FTEs. The actual hiring determines whether it is known and measurable, but it does not necessarily make it reasonable and justified. The perceived need of additional employees would be borderline to being known and measurable. However, a wish to fill vacancies that have existed in the past, still exist today, and that will continue to exist in the future, is not a known and measurable increase to the employee complement. While a vacancy at December 31, 2003 may have been filled, a new vacancy can and will occur. As of December 31, 2003, there were 514 employees on the payroll. On January 8, 2004, the employee count was 508. As of August 17, 2004, the Company had a net increase of 20 employees. That means 21.5 FTES are still not known and measurable.

Q. WHY IS THERE A NEED FOR THE INCREASE IN EMPLOYEES?

A. The Company states that 16 of the additions are succession employees. The trend for electric companies is that the technical workforce has a number of employees eligible for, or soon to be eligible for, retirement. Qualified replacements need up to four years of training, so ratepayers are being asked to pay for an increased number of workers to do the same job previously done by the current employee complement. Unfortunately for ratepayers, the two for one is an unavoidable cost of doing business, even though the

Company says that it had not done a good job of succession planning. Other additions that have been proposed by the Company are filling vacancies, adding staff to replace contract workers, filling positions the Company claims should not have previously been eliminated, and to fill new positions required to meet new business needs.

Q. WHAT NUMBER OF POSITIONS ARE YOU RECOMMENDING BE REMOVED FROM THE COMPANY REQUEST?

A. The Company's turnover rate more than justifies not allowing 11 of the vacancies. According to DPS 1-44, as of August 17, 2004, 12 employees have left CVPS in 2004. Based on the five year average vacancy rate of 6.2%, it would not be unusual for as many as 20 additional employees to leave CVPS by year end. The lowest number of employees to leave in any one year since 1999 has been 25. As stated before, vacancies will always exist and to ask ratepayers to pay for the vacant positions is not appropriate. A reduction of 11 FTEs is recommended.

The remaining 10.5 vacant positions are questionable. The Company has stated in response to DPS 3-56, that it failed to remove at least $67,612 of contractor costs being replaced by the added positions, and that without the added legal and the accountant jobs, contracted rate year services would have been higher. At this time, we are not recommending removal of the remaining 10.5 positions that have yet to be added.

Q. IS THERE A REASON TO BE CAUTIOUS ABOUT ALLOWING THE 10.5

POSITIONS?

A. Yes. The 10.5 positions are not truly known and measurable. As indicated earlier, the December 31, 2003 count for payroll annualization was 514. As of August 17, 2004, a net 20 positions have been added for a total of 534. Based on the response to DPS 5-18, the original budgeted FTEs for 2005 was 532.2. By adding 10.5 positions to the current 534, you would have 544.5 positions, which is 12.3 positions over budget. An incentive compensation goal is to be at or below budget, and going over budget in payroll could impact the ability to attain that goal, thereby possibly limiting the incentive payout. The adding of employees over budgeted level flies in the face of the incentive goal of reducing costs. The allowing of the 10.5 positions further justifies the disallowance of some of the EIP expense, and may warrant increasing the disallowance.

It should also be noted that the addition of some positions is attributed to complying with the Sarbanes Oxley Act (SOX) requirements. The purpose of SOX is to improve the quality of corporate disclosure and financial reporting. The reason it came about is because shareholders of various corporations appointed directors who hired officers who were not exactly honest, which in turn caused financial losses to the shareholders and honest employees of the corporations. The changes implemented are not so much in the task to be performed, but in getting someone to accept ultimate responsibility for the task. For example, internal control procedures should have always existed, and now with SOX, the outside auditor must assess in writing whether management's written assertion that adequate controls exist is accurate. Accountability is the requirement of SOX to provide protection to shareholders. The cost for that shareholder benefit is being charged to ratepayers. It is true that it is a cost of business, but ratepayers should not be required to continually pay for protecting shareholders from the shareholder's own bad decisions. The Company's filing includes an increase in SOX spending over test year amounts of at least $200,000 in Rate Year 1 and $100,000 in Rate Year 2.

Q. HOW DID YOU DETERMINE THE ADJUSTMENT FOR THE 11 VACANCIES?

A. As shown on Schedule 11, page 2, the average expensed compensation for the 34.5 positions added by the Company in Rate Year 1 was $24,806. The $24,806 multiplied by 11 is $272,866. The Rate Year 1 expense for additional employees is reduced by $272,866 from $855,814 to $582,948. In Rate Year 2 the adjustment is a reduction of $358,280 based on an average Rate Year 2 expense of $32,571 per addition.

Q. IS THERE ANY OTHER ADJUSTMENTS TO PAYROLL?

A. Yes. First, the Company has indicated that the Rate Year 2 overtime is overstated and should be reduced from $372,089 to $280,914, a reduction of $91,175. Next, the officers provide a different level of service to the regulated and unregulated operations than the general employee complement. Some also will participate in efforts to influence legislation as well as perform unregulated services. Three attempts to identify and verify that a reasonable level of costs was charged below the line was unsuccessful. The Company was asked in DPS 1-24 for detail on wages charged to other operations, and the response was not detailed and eventually stated that "salaries and wages charged to subsidiaries is not included in the Company's rate filing." When asked in DPS 1-14 to provide a breakdown of officer compensation by account, the response stated "a breakdown of each officer's compensation is not readily available, other than what is provided on page 104 of the FERC Form 1." Finally, when the below-the-line amount of compensation for Mr. Rocheleau and Mr. Rogan was requested, the Company again explained that the allocation process caused it to lose its identity. The bottom line is that we do not know what officer compensation was charged below the line, if any; and why it was charged below the line, if it was, cannot be ascertained.

Because the Company has failed to justify that an appropriate level of compensation has been charged below-the-line, it is recommended that $96,514, or 10% of the $965,147 purported to be in the annualized officer salaries before rate year wage increases are added, be removed from each of the rate years. This amount may be conservative.

Q. WHY DID YOU REFER TO THE AMOUNT AS PURPORTED?

A. The response to DPS 3-53 states that Column E of Workpaper 1C6-1 has $965,147 of officer compensation. The total of Column E of Workpaper 1C6-1 is $22,929,723 and on workpaper 1C6-10, Column A, the total salaries of $22,929,723 includes $1,220,084 of compensation identified as "Officers." Assuming the $1,220,084 is correct, it would make the $96,514 adjustment conservative. It suggests that the officer compensation adjustment should be greater and that the amount actually charged below-the-line is minimal.

PAYROLL TAX EXPENSE

Q. WHAT ADJUSTMENT IS REQUIRED FOR THE PAYROLL TAX EXPENSE ASSOCIATED WITH THE PAYROLL ADJUSTMENT?

A. As shown on Schedule 12 of Exhibit DPS-L&A-1, the social security expense should be reduced $53,332 in Rate Year 1 and $82,150 in Rate Year 2. The adjustment was calculated by multiplying the respective recommended payroll expense adjustments by the test years effective social security rate of 7.12%.

MEDICAL INSURANCE

Q. HAVE YOU REVIEWED THE REQUESTED MEDICAL INSURANCE EXPENSE?

A. Yes. The Company's request in Rate Year 1 for active employees is $3,538,852 for an <u>average expense</u> of $6,652 per employee. The average cost per employee, prior to capitalization, is $10,118. A Hewitt Associates study that the Company used for a comparison of the Company's cost to a national average shows the <u>national average total cost</u> per employee in 2003 to be $6,295. This is shocking when you consider the CVPS average total cost per employee is $10,118. Per the response to DPS 5-13, the CVPS average employee health care cost is 61% higher than the national average because "CV has generous medical program design."

Q. SHOULD THE FACT THAT CVPS IS SELF INSURED IMPACT THE COSTS IN THE COST COMPARISON?

A. It could impact it some, but in the Yankee Gas Service Company (Connecticut) proceeding that we are participating in the 2003 test year, total average cost per employee was $6,599. Yankee Gas is self insured and has approximately 500 employees. Based on the comparisons, we would agree with CVPS that they have a “generous medical program.”

Q. IS THE COMPANY’S REQUESTED INCREASE APPROPRIATE?

A. No. First, the inflation rates used in determining the increase are high. Second, in the response to DPS 5-13, the Company states that CVPS has increased the employee contribution in 2004 to 19%. The filing does not reflect a reduction in cost, instead it reflects a 14% increase in 2004 and 12% in 2005 and 2006. The medical insurance expense in the filing is excessive.

Finally, it is difficult to understand how the 14% increase in 2004 can be requested when according to the response to DPS 3-97, the Company plans to implement a program that will “substantially lower employee premiums.”

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO MEDICAL INSURANCE EXPENSE?

A. Yes. The medical insurance expense should be reduced $755,998 in Rate Year 1 and $876,868 in Rate Year 2. These adjustments are reflected on Schedule 13 for each rate year.

Q. HOW DID YOU DETERMINE YOUR ADJUSTMENT?

A. As shown on Schedule 13 for Rate Year 1 and Rate year 2, we started with the test year expense. We reduced the active employee expense by 4% to reflect the increase in employee contributions referred to in DPS 5-13. The respective adjusted test year amounts were then increased by the projected inflation rate for the rate years. The inflation rates used were 8% in 2004, 7% in 2005, and a prorated 6% in 2006.

Q. WHY DID YOU USE DIFFERENT INFLATION RATES THAN THOSE PROJECTED BY THE COMPANY?

A. The rates used by the Company are considered excessive. In DPS 3-27, the Company indicated the cost reflected were provided by the Company's benefit consultants. The response identifies the 14% and 12% rates used by the Company in projecting costs. Further inquiry directed us to workpaper C10-2 that is a letter from Towers Perrin identifying the medical inflation. The letter notes that the rates were provided to Towers Perrin by the Company, not determined by Towers Perrin. The lower rates utilized for each year was from the Tower Perrin's most recent FAS 106 actuarial report. Also, the lower rates, if used by the Board in their Order, should act as an incentive for the Company to lower its cost to a more reasonable level. The cost per employee at CVPS is too high and is not appropriate considering some of the ratepayers who are contributing towards the payment of that cost may not even have health insurance. The Company's failure to maintain its health care cost at a reasonable level is bordering on imprudence.

401(k) EXPENSE

Q. HOW DID YOU DETERMINE YOUR ADJUSTMENT TO 401(k) EXPENSE ON SCHEDULE 14?

A. We took the test year payroll expense and the test year 401(k) contribution factor of 2.95%. For each rate year we took our recommended payroll expense and applied the 2.95% contribution factor to arrive at the projected expense for each respective rate year. After comparing our calculation of 401(k) expense to the Company's calculation we determined a reduction to expense of $22,028 and $33,954 was required for Rate Year 1 and Rate Year 2, respectively.

INCOME TAX EXPENSE

Q. WHAT IS THE PURPOSE OF THE ADJUSTMENT TO INCOME TAX EXPENSE PRESENTED ON SCHEDULE 16?

A. The adjustment presented on Schedule 16 reflects the impact of our recommended adjusted Return on Utility Rate Base and the weighted cost of debt rate on the Company's proposed income tax expense. The calculations are identical to the Company's calculations, with two exceptions. We replaced CVPS's proposed return on utility rate base amount with our recommended amount. Additionally, in calculating the interest expense reduction from the return on utility rate base, we substituted the Company's rate base amount with the Department's recommended rate base and used the Company's weighted cost of debt.

GROSS REVENUE & FUEL GROSS RECEIPTS TAX

Q. HOW WAS THE ADJUSTMENT FOR GROSS REVENUE AND FUEL GROSS RECEIPTS TAX EXPENSE DETERMINED?

A. The adjustment on Schedule 17 was determined the same way as the Company calculated its expense. Because our gross revenue changed the tax changes based on a factor as calculated by the Company. This is what is referred to as a flow through adjustment.

UNCOLLECTIBLES EXPENSE

Q. IS THE ADJUSTMENT TO UNCOLLECTIBLE EXPENSE ON SCHEDULE 19 FLOW THROUGH ADJUSTMENT?

A. Yes. As the revenue requirement changes the uncollectible expense changes. Here, again, we used the Company factor and flowed the change through.

REGULATORY COMMISSION EXPENSE

Q. WHAT AMOUNT HAS CVPS INCLUDED IN COST OF SERVICE FOR REGULATORY COMMISSION EXPENSE?

A. In COS adjustment Number 16, CVPS included $946,092 for regulatory commission expense, which was $356,596 more than the actual recorded test year level. The requested amount is based on the five-year average of costs incurred for various dockets at both State and FERC levels. The level of costs incurred over the five-year period ranged from a low of $569,579 during the year ended December 31, 2002 to a high of $1,245,520 during the year ended December 31, 1999.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENT TO THE REQUESTED EXPENSE LEVEL?

A. Yes. As shown on Schedule 18, we recommend that the cost associated with two specific cases be removed for purposes of calculating the five-year average cost level. The cases include Vermont PSB Docket No. 6133 - Holding Company and the Patch Case in Federal District Court. The costs associated with the two dockets should not be charged to Vermont ratepayers; consequently, the costs should be excluded in calculating the five-year average expense level. Removal of these two dockets results in a $180,735 reduction in CVPS's requested regulatory commission expense.

Q. WHY DO YOU RECOMMEND THAT COSTS ASSOCIATED WITH DOCKET 6133 BE REMOVED FROM THE FIVE-YEAR AVERAGE CALCULATION?

A. The purpose of Docket 6133 was for CVPS to set up a separate holding company in preparation for potential electric industry deregulation. The formation of a separate holding company would primarily benefit CVPS's shareholders, not its ratepayers. Consequently, the ratepayers should not be responsible for funding such costs. As shown on Schedule 18, expenses of $403,951 were incurred in the four-years ended December 31, 2002 for this docket. These amounts should be removed in calculating the five-year average expense level.

Q. PLEASE DISCUSS THE PATCH CASE.

A. Included in the five-year average regulatory expense calculation is $431,759 recorded as expense on CVPS's books in the four years ended December 31, 2002 for the Patch Case. This is only 50% of the total costs associated with the case in those periods, as the other 50% was recorded on the books of Connecticut Valley Electric Company Inc. (CVEC).

The NHPUC denied CVEC's recovery of a portion of power costs for power purchased from Central Vermont. The NHPUC determined that CVEC was imprudent for not terminating its FERC authorized power contract with Central Vermont to take advantage of lower market costs. This issue had been the subject of several New Hampshire decisions and numerous appeals at both the New Hampshire state and the Federal level. According to CVPS's response to DPS 3-106 in Docket No. 6460, "Central Vermont and CVEC joined a federal district court action (the Patch Case) initiated by Public Service Company of New Hampshire to argue that FERC has exclusive jurisdiction over CVEC's ability to recover wholesale power costs from its retail customers." The response also indicated that the federal district judge in that case upheld FERC's exclusive jurisdiction and CVEC's right to recover the associated power costs. The circuit court of appeals affirmed the federal district judge's decision.

Q. SINCE THE PATCH CASE CLEARLY INVOLVES DECISIONS AND ACTIONS THAT WERE TAKEN IN THE NEW HAMPSHIRE JURISDICTION, WHY HAS THE COMPANY INCLUDED THE COSTS ON CVPS'S BOOKS IMPACTING THE VERMONT RATEPAYERS?

A. In response to DPS 3-106(b) in Docket No. 6460, the Company indicated that in both the

Federal and FERC proceedings, the New Hampshire Public Utility Commission was "...trying to shift CVEC's stranded costs to Central Vermont and its Vermont retail customers." The Company also indicated that the benefits of this case went to both CVEC and the Vermont retail customers, so it split the costs 50/50 between CVEC and Central Vermont.

In rebuttal the Company said that the costs should be shared because it would impact the wholesale allocation factor. That argument cannot be made any longer because the sale of CVEC has already shifted the allocated CVEC costs to Vermont ratepayers.

Q. IS THE COMPANY'S REASONING COMPELLING?

A. No, it is not. The case involves decisions made by the New Hampshire Public Utility Commission regarding costs incurred by CVEC to be passed on to CVEC's New Hampshire customers. Vermont ratepayers should not, in any way, be responsible for funding any of the associated legal costs, and should definitely not be responsible for 50% of those costs. On Schedule 18, we removed all of the costs associated with this New Hampshire case from the calculation of the five-year average regulatory commission expense.

CATV POLE ATTACHMENT REVENUES

Q. WHAT IS THE PURPOSE OF YOUR ADJUSTMENTS TO RATE YEARS 1 AND 2 TO INCREASE CATV POLE ATTACHMENT REVENUES ON SCHEDULE 20

A. On CVPS Workpaper C21-2, the Company calculated the amount of CATV pole attachment revenue by rate type and by joint versus sole use. The initial calculation presented on the workpaper was based on the actual number of joint and sole poles at each tariff rate, which is either Tariff 1 foot rate or Tariff 2 foot rate, based on the actual pole counts as of December 31, 2003. This resulted in preliminary rate year revenue of $866,585. CVPS then applied two separate adjustments, significantly reducing the calculated amount of pole attachment revenues to be collected in each of the rate years. We disagree with the application of the two adjustments and recommend that pole attachment revenues be included in rates based on the preliminary revenue amount of $866,585.

Q. COULD YOU PLEASE DISCUSS THE ADJUSTMENTS MADE BY CVPS TO ITS PRELIMINARY CALCULATION?

A. Yes. Adjustment 1 to the preliminary amount is identified in the workpaper as "Adelphia gets 1 foot rate." In this adjustment, CVPS shifted a significant portion of the poles falling under the Tariff 2 foot rate to the Tariff 1 foot rate. This reduced the preliminary rate year revenue amount from $866,585 to $493,500. Adjustment 2 is identified as "Tariff rate settled 15% lower" and reduces the projected revenues by an additional $74,025. According to the direct testimony of CVPS witness Scott R. Anderson, at page 5, in on-going Docket No. 6605 there is an issue outstanding of whether or not Adelphia is a simply a cable provider or not. CVPS contends in Docket No. 6605 that Adelphia is more than a cable provider and therefore must pay a higher fee pursuant to the tariff. According to the response to DPS Data Request 1-46, CVPS maintains that in addition to being a cable company, Adelphia provides telephone services and therefore must pay a higher fee. Adelphia disputes this contention, which is being addressed as part of Docket No. 6605. In its adjustment, the Company has estimated the number of attachments that would move to a Tariff 1 foot rate instead of the current Tariff 2 foot rate as a result of Docket No. 6605.

Q. WHY DO YOU DISAGREE WITH THE COMPANY'S PROPOSED ADJUSTMENTS?

A. At this point, Docket No. 6605 has not been resolved and is still open. At this point, CATV pole attachment revenues should be included based on the known and measurable amounts provided in the Company's preliminary rate year revenue calculation. It is not known or measurable at this point whether the significant shifting between the Tariff 1 foot rate and the Tariff 2 foot rate will occur, or if Adelphia will be successful in achieving the 15% discount. In Schedules 20 for each rate year, we have increased Rate Year 1 and Rate Year 2 CATV pole attachment revenues, respectively, by $447,110 to reflect the preliminary rate year amounts prior to the estimated reductions.

SALE OF CVEC

Q. WHAT IMPACT HAS THE SALE OF CVEC HAD ON THE RATE FILING, VERMONT RATEPAYERS AND CVPS?

A. The Company's proposed treatment for the impact from the sale results in additional costs to ratepayers and a $6.649 million gain to shareholders.

Q. HOW DOES THE COST INCREASE FOR VERMONT RATEPAYERS?

A. Please refer to Exhibit DPS-L&A-3, which is Attachment 3-87 to the response to DPS 3-87. This depicts what the test year costs were and, as noted on line 27, there is $12,452,000 of cost allocated to wholesale. The majority of the costs are costs being assigned to CVEC. Included in the $12,452,000 is approximately $7,710,000 (128,502,000 x 6%) of purchased power, most of which is CVEC power costs. By subtracting the $7,710,000 from the $12,452,000, you get $4,742,000 of other costs allocated to wholesale exclusive of purchase power. Using the current 1.10% allocation to wholesale the new allocation, including purchase power, would be $2,896,000 (263,262,000 x 1.1%). The difference between the pre-CVEC sale wholesale allocation of $4,742,000 and the current wholesale allocation of $2,896,000 is $1,846,000. As rough a calculation as it may be, the result indicates that approximately $1.8 million of additional costs to Vermont ratepayers, or as Jean Gibson refers to it in her prefiled testimony, the "loss of economies of scale and scope attributable to the CVEC sale." In response to DPS 3-17 the Company states that:

> With the CVEC sale, there is one less entity under the CVPS consolidated

> umbrella to allocate common costs with the near term result that more common costs must be recovered from the Vermont utility customers in order for the Company to have the opportunity to earn its allowed rate of return on common equity.

The short and direct response to whether Vermont ratepayers are picking up added cost is an unequivocal yes. This added cost is in addition to the service contract costs that the Company is requesting Vermont ratepayers to pay for.

Q. HOW IS IT THE SALE OF CVEC INCREASES COSTS FOR VERMONT RATEPAYERS?

A. General operating costs are shared by the consolidated entity and if a proportionate amount of the costs shared do not leave with the entity sold the remaining members of the consolidated entity pick up the left over costs. When CVEC left CVPS, only a handful of employees left CVPS. Some operation costs and the administrative costs remained, and since CVPS is the major entity in the consolidated group, the Vermont ratepayers get stuck with the bill.

Q. ARE THE RATEPAYERS HARMED BY THE POWER COST PORTION OF THE WHOLESALE ALLOCATION?

A. Theoretically, they are not. The Company recorded the estimated loss and a future liability for power costs through 2016 on January 1, 2004. The liability is proposed to be amortized over 12 years as a reduction to the actual power cost obligation recorded and paid in the respective year. This proposed treatment will, according to DPS 5-29, "protect

Vermont ratepayers from the effect of the termination of the RS-2 power contract."

Q. WHAT IS YOUR CONCERN WITH THIS TREATMENT?

A. The loss recorded is based on market price and as the transaction shows a significant change can occur over a short period of time. When the initial calculation was made, it was estimated that the loss would be $21 million. When the closing occurred, the estimated loss became $14.351 million, resulting in the $6.649 million gain recorded by CVPS on January 1, 2004. Now if market prices improve, the additional revenue coupled with the amortization will result in increased net income. That increase flows to shareholders because utilities do not generally come to the regulatory agency asking for a decrease in rates without being asked to do so.

Q. WHY IS THE GAIN FROM THE POWER CONTRACT FLOWING THROUGH TO SHAREHOLDERS?

A. In response to DPS 5-2 the Company first states the impact of the "CVEC sales proceeds for CVPS is appropriately not reflected in Rate Year 1 or Rate Year 2." Next, the Company states, "First, the receipt of wholesale revenues occurred after the test year, before the rate years, and is a one-time event, all of which preclude inclusion in the Cost of Service." In other words, the closing took place in the three month window between the test year and Rate Year 1. However, I do not agree that the timing precludes the recognition of the gain to cost of service.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO REFLECT THE GAIN IN COST OF SERVICE?

A. Yes. The $6.649 million gain should be flowed back to ratepayers over a three year period. The $2.216 million reduction to cost of service will offset the additional cost Vermont ratepayers are absorbing due to the loss of economics of scale that resulted from the transaction undertaken for the benefit of shareholders. The amortization of the gain is only temporary relief for Vermont ratepayers, whereas the increase in cost absorbed is permanent unless management finds a way to eliminate some of these costs.

Q. WHAT MAKES THE TRANSACTION BENEFICIAL TO SHAREHOLDERS?

A. Because of changes in regulation in New Hampshire the sale of CVEC allows shareholder to avoid possible losses due to stranded costs not being recoverable.

Q. WHAT IF THE BOARD DOES NOT ALLOW AN AMORTIZATION OF THE GAIN TO RATEPAYERS?

A. An alternative adjustment would be to increase the calculated wholesale allocation by the estimated $1.8 million of costs added to Vermont ratepayers because the transaction was essentially for the benefit of shareholders.

SAFETY TRAINING COSTS

Q. CVPS' FILING INCLUDES AN ADJUSTMENT TO INCREASE EXPENSES ASSOCIATED WITH SAFETY TRAINING. ARE THERE ANY PROBLEMS WITH

THE ADJUSTMENT?

A. Yes. In calculating the adjustment for increased training costs, the Company mistakenly picked up the amount of discount to CVPS for the training instead of the actual training cost to CVPS. In response to DPS 3-76, the Company agreed that the costs were incorrectly reflected in COS Adjustment No. 22.

Q. WHAT ADJUSTMENTS NEED TO BE MADE TO CORRECT THE ERROR?

A. The adjustments to correct the error are presented on Schedules 21 for Rate Year 1 and Rate Year 2. As shown on the schedules, rate year 1 and rate year 2 adjusted expenses need to be increased by $9,000 and $8,000, respectively.

DIRECTORS & OFFICERS LIABILITY INSURANCE

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE LEVEL OF DIRECTORS AND OFFICERS LIABILITY INSURANCE INCLUDED IN THE RATE YEARS?

A. Yes. The purpose of Directors and Officers (D&O) liability insurance is to provide protection to shareholders from the shareholders' own decisions. Shareholders elect the Board of Directors who are responsible for the appointment of officers of the company. Directors and Officers are compensated to provide quality leadership and serve with integrity. Ratepayers have no choice in who manages the Company and who serves on the Board of Directors, and ratepayers will not be compensated by insurance companies for losses incurred by shareholders for management's mistakes or improprieties. Therefore, shareholders should be responsible for their decisions regarding management of the Company. The cost associated with the protection of the shareholders' investment should be borne by the shareholders. D&O liability insurance expense should be removed. In the event the Board determines that ratepayers should be responsible for a portion of the D&O insurance cost, which we do not recommend, then the amount included in the rate year should, at a minimum, be reduced significantly. It must be remembered that a fallout from the mistakes and improprieties of shareholders and management of certain corporations is now increasing the costs of Vermont ratepayers through the implementation of SOX requirement.

Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE EXPENSE INCLUDED IN THE RATE YEARS FOR D&O LIABILITY INSURANCE?

A. Expenses in rate years 1 and 2 should be reduced by ****BEGIN CONFIDENTIAL**** $INSERT C. ****END CONFIDENTIAL**** This reduction is reflected on Schedule 2 for each rate year.

Q. WHAT IS YOUR RECOMMENDED ALTERNATIVE ADJUSTMENT SHOULD THE BOARD DETERMINE THAT A PORTION OF D&O LIABILITY INSURANCE SHOULD BE BORNE BY RATEPAYERS?

A. Between the historic test period of December 31, 2003 and the prior year, there was a significant increase in the amount of D&O liability insurance expense. This increase in premiums has been typical across the nation and is attributable to the recent accounting scandals of entities such as Enron, Global Crossing and Worldcom. Shareholders, not Vermont ratepayers, should be responsible for the resulting increase in premiums. Consequently, in the event our recommended adjustment to remove 100% of the cost is not adopted, then we recommend that D&O liability insurance first be reduced by the increase in premium occurring between 2002 and 2003. The remaining balance, which is the 2002 expense level, should then be shared 50/50 between ratepayers and shareholders. According to the response to DPS 1-36, the D&O insurance expense increased from **BEGIN CONFIDENTIAL** $INSERT D **END CONFIDENTIAL** in 2002 to **BEGIN CONFIDENTIAL** $xxxxxxx**END CONFIDENTIAL** in 2003. It is this 2003 amount that remains in rate years 1 and 2. Under our alternative recommendation, D&O insurance expense should be reduced by **BEGIN CONFIDENTIAL** $xxxxxxx **END CONFIDENTIAL**. This adjustment removes 100% of the increase in premium occurring between 2002 and 2003 and 50% of the remaining balance.

Q. DO YOU HAVE ANY ADDITIONAL CONCERNS WITH THE LEVEL OF D&O INSURANCE COSTS BEING INCURRED BY CVPS?

A. Yes. In the supplemental response to DPS 3-97, CVPS provided pages from the Board of Directors meeting minutes date 2/23/04 as Attachment 3-97v. *** BEGIN CONFIDENTIAL***xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx. ***END CONFIDENTIAL * * *

______SERVICE CONTRACT

Q. WHAT IS THE SERVICE CONTRACT ADJUSTMENT THAT THE COMPANY MADE?

A. With the sale of CVEC, the previous service agreement for contract services was cancelled. In other words, CVPS provided services to CVEC and billed CVEC for those services. Now that CVEC is gone, the services cannot be billed out. The Company is of the opinion that those costs should be paid for by Vermont ratepayers.

Q. IF THE COSTS ARE INCURRED, SHOULDN'T VERMONT RATEPAYERS PAY FOR THEM?

A. No. First, the Company was asked in DPS 1-24 for detail on the service contract wages, as shown in the FERC Form 1, and the response stated those wages are not in Company rate filings. It did not want to provide the detail for analysis, so it is not appropriate to now incur a portion of those costs in rates. Next, these costs were borne by New Hampshire ratepayers. The opportunity to have those cost continue to be billed to New Hampshire ratepayers went away when shareholders and management decided to sell CVEC. The decision to sell CVEC was made by management and shareholders, each of which have a responsibility to Vermont ratepayers to provide quality service at a reasonable cost. The service to Vermont ratepayers is the same today as it was in December of 2003, yet the cost of that service went up by approximately $1.8 million due to the change in the wholesale allocator plus $1.9 million for the elimination of the service contract. This adjustment really appears to be a double charge for the same cost. If it is not, then CVPS is asking for Vermont ratepayers to pay an additional $3.7 million without Vermont ratepayers receiving any additional service and/or benefit. Vermont ratepayers should not be required to bear extra expense for a decision that was made for the benefit of shareholders and because detail on test year costs that are being put above the line was not supplied as requested.

Q. WHY DIDN'T THE COSTS FOR SERVING CVEC CUSTOMERS GO AWAY WHEN CVEC WAS SOLD?

A. According to Jean Gibson, these are costs that are the result of the loss of the economies of scale. There is something wrong with that though. When a part of an operation is sold, you would expect that overall costs will decline. The filing shows that the cost to Vermont ratepayers will do just the opposite, with no offsetting reductions.

Q. WHAT ADJUSTMENT SHOULD BE MADE TO THE COMPANY SERVICE CONTRACT ADJUSTMENT REQUEST?

A. The $1,912,000 requested in Rate Year 1 should be disallowed, as well as the $2,014,000 in Rate Year 2.

COST SAVINGS FROM CAPITAL ADDITIONS

Q. THE COMPANY'S FILING INCLUDES NUMEROUS CAPITAL ADDITIONS OCCURRING DURING THE PERIOD JANUARY 1, 2004 THROUGH MARCH 31,

2006. HAVE ALL OF THE COST SAVINGS RESULTING FROM THE CAPITAL ADDITIONS BEEN ADEQUATELY REFLECTED IN THE FILING?

A. No. We are recommending several adjustments in order to match the projected O&M cost savings with the capital additions included by CVPS in its filing. Projected cost savings have not been reflected in the filing for the following plant additions: purchase frame for robot WO 6682; purchase network printer, Rutland WO 6778; and Tivoli Enhancement WO 6782.

Q. WOULD YOU PLEASE DISCUSS EACH OF THESE PROJECTS AND THE AMOUNT OF RECOMMENDED ADJUSTMENT TO RATE YEARS 1 AND 2 EXPENSES TO REFLECT THE ASSOCIATED COST SAVINGS?

A. Yes. We will discuss each, in order, below. Each of these savings are reflected on our Schedules 22 for Rate Year 1 and Rate Year 2.

<u>Purchase frame for robot WO 6682</u> The Company has eliminated old mainframe tape technology, eliminating the last four of its 3480 tape drives. This project results in $10,000 in O&M annual savings in maintenance fees. At page 34 of his direct testimony, CVPS witness Jeffrey Monder agrees that the $10,000 in annual equipment maintenance cost savings should be reflected in both Rate Years 1 and 2, but was overlooked in preparing Cost of Service Adjustment 27. We have reflected this adjustment, which the Company agrees with, on our Schedules 22 for both rate years.

<u>Purchase network printer, Rutland WO 6778</u> CVPS has included a $55,390 addition to

plant in service for this project beginning in March 2004. The project replaces an old printer with a high speed network printer/copier/scanner. The direct testimony of CVPS witness Jeffrey Monder, at page 9, indicates that the new printer will provide small savings in operating costs initially and greater savings once CVPS switches to a single sheet bill. According to the cost/benefit analysis attached to the work order for the project, annual O&M savings will be $28,000 with new annual O&M costs to be incurred of $7,500. The net O&M savings as a result of this project, based on the cost benefit analysis, is $20,500 ($28,000 - $7,500).

<u>Tivoli Enhancement WO 6782</u> CVPS has included $160,000 additions for May 2004 for this project. The project is to offload central processing unit cycles from the mainframe to avoid an upgrade. The workorder and cost/benefit analysis for this project was provided by the Company as Exhibit CVPS JM-2, attached to the testimony of CVPS witness Jeffrey Monder. In his testimony, Mr. Monder, at page 13, indicates that the project will result in a large reduction in mainframe operating costs, yet no cost savings were reflected in the proceeding. According to the cost/benefit analysis provided with the workorder during our on-site review, the projected annual O&M cost savings for the project are $94,200 consisting of savings on the current mainframe lease and mainframe savings, with projected increases in costs of $14,400 for maintenance. In year 2, the maintenance cost increases an additional $10,000 to $24,400. This results in a net O&M cost savings from the project of $79,800 in year 1 and $69,800 in year 2. Consequently, Rate Year 1 O&M expenses should be reduced by $73,159 to reflect 11 months of cost savings and Rate Year

2 O&M expense should be reduced by $69,800 to reflect 100% of year 2 cost savings associated with this capital addition. These adjustments are reflected on Schedules 22 for Rate Years 1 and 2.

DEPARTMENT PENALTY

Q. WHAT IS THE PURPOSE OF YOUR ADJUSTMENT ON SUMMARY SCHEDULE 2 FOR BOTH RATE YEAR 1 AND RATE YEAR 2 TITLED "REMOVE DEPARTMENT PENALTY"?

A. During the historic test year, CVPS recorded $31,000 in Account 921 for a penalty imposed by the PSB as a result of Docket No. 6758 - Investigation into Fourteen Utilities' Provision of Service to Customers Pursuant to Expired Special Contracts or at Special Rates Without Board Approval. In the Opinion and Order in that docket, dated December 16, 2002, CVPS was required to pay a $31,000 penalty. This penalty should not be included in rates and should be removed from Rate Year 1 and Rate Year 2 expenses. The removal of the $31,000 penalty is reflected on our Summary Schedules 2 for both rate years.

MISCELLANEOUS EXPENSE

Q. ARE THERE ANY ADDITIONAL EXPENSES INCURRED BY CVPS IN THE HISTORIC TEST YEAR THAT SHOULD BE REMOVED FROM RATE YEARS 1 AND 2?

A. Yes. As part of our on-site review, the Company provided copies of several invoices. One of the invoices provided consisted of support for $3,500 recorded in Account 921 in February 2003. The invoice was from the Committee for Citizen Awareness and is described as: "The payment of this invoice will cover the first (of two) $3,500.00 expense for the production and distribution of the 'Patriotism and You' videotape in the State of Congressional District of Vermont." The invoice indicated that the invoice for the final payment would be sent in the next year. These costs should have been recorded below the line. Ratepayers should not be required to fund these types of costs in rates. On Summary Schedules 2 we have removed the $3,500 from expenses for both Rate Year 1 and Rate Year 2.

TREE TRIMMING AND POLE TREATING

Q. ARE YOU RECOMMENDING ANY ADJUSTMENT TO THE COMPANY'S TREE TRIMMING REQUEST?

A. No. The Company's trimming program appears to be one of the better programs that we have reviewed. However, the Company has indicated the program is lagging and is not at the desired trim cycle. Tree trimming can be a contentious issue in rate cases because there is usually a significant increase in costs being requested. This proceeding is no different because the Company is requesting a $1,768,000 increase. The additional $1,786,000 represents a 33.9% increase over the test year expense of $5,221,854.

Q. WHY AREN'T YOU RECOMMENDING AN ADJUSTMENT WHEN SUCH A LARGE INCREASE IS BEING REQUESTED?

A. During the test year the Company did not do any pole treating and that alone accounts for $523,000 of the requested increase. In order to be able to provide reliable and safe service the system requires proper maintenance. In reviewing the transmission and distribution vegetation management plans, along with the annual spending, it was determined that the requested expense amount was not only reasonable, but necessary.

Q. ARE THERE ANY CONCERNS WITH THE TREE TRIMMING AND POLE TREATMENT PROGRAM?

A. There are two concerns. First is that the Company be accountable for the amount ultimately allowed in rates. Too often utilities will request an amount in rates and when cost cutting takes place the tree trimming budget, because of its size, is reduced. It is recommended that the Company be required to expend its annual allowance for tree trimming and pole treating. This could be done by requiring the Company to record at least the amount allowed in rates as an expense every year. If spending does not occur at the allowed level an accrued regulatory liability can be established for the amount of the shortfall. Then in year two the Company will first, charge the liability account to clear out the balance, and then charge the remaining amounts expended in the year to expense. This accountability provides a level of assurance that the allowed cost for tree trimming is expended, and not a victim of budget cuts.

Q. WHAT IS THE SECOND CONCERN?

A. In our discussions with the Company, and in response to our discovery, it appeared that the telephone companies are not paying their fair share of the costs. It is recommended that the Board review this inequity, and possibly establish some requirement for cost sharing. According to DPS 1-47, neither Verizon or Shoreham share in maintenance of tree trimming.

MANAGEMENT

Q. DID YOU MAKE ANY ASSESSMENT OR EVALUATION OF MANAGEMENT DURING THE DISCOVERY PHASE OF THIS PROCEEDING?

A. To some degree we reviewed management, but we did not perform in-depth interviews with management personnel. Our assessment was based on discovery requests.

Q. WHAT DID YOU DETERMINE FROM YOUR REVIEW?

A. The Company is in a catch up mode, but I think it is more due to being required to do so than being voluntary. SOX has instilled a new thought process in corporate America. It is no longer okay to just say internal controls are in place because SOX is making auditors and officers take responsibility for financial decisions and reporting. Additionally, management's actions and/or performance has not instilled confidence in the employees of CVPS.

Q. WHAT SUGGESTED TO YOU THAT MANAGEMENT IS IN A REQUIRED CATCH UP MODE?

A. The first clue was the accounting policies and procedures manual requested during our informal discovery. The manual should be current, but when reviewed on-site we found a vast majority of the pages outdated, in fact, the predominant date was 1992. When copies of select pages were requested notes were provided saying that it no longer applied or a different version was supplied. We were informed, while on-site, that the manual was being updated because of SOX. It was also indicated that a number of tasks or procedures were being revised for compliance with SOX. The Corporate policy and procedures manual was found to be more up-to-date, but it still has some procedures that have not been updated and/or reviewed in more than four years.

Q. WHAT OTHER CONCERNS DID YOU IDENTIFY?

A. In 1998, a management review was performed and a number of recommendations were made, some of which seem to have not been addressed. One recommendation was to improve variance reports. Although the report was directed at capital budget variances the Company should have applied the recommendation to O&M expense variances as well. Based on the most detailed variance reports that we were provided in this proceeding the variance reports have not improved since we first reviewed CVPS records back in the early 1990s. The reports are very broad and do not provide detailed explanations for variances.

Another item listed in the report was that the Company was to develop a management succession plan for all CVPS officers. A request was made to determine where management succession was discussed in the Corporate Policy & Procedure manual. The response to DPS 3-96 stated the following:

> Management succession of CVPS officers is addressed in the Board of Director's Compensation Committee Charter. Under "Committee Responsibilities" the charter states: "Develops plans for succession of the CEO and other officers when appropriate."

The statement does not develop a succession plan.

The next concern was related to Ms. Gamble's assertion that the Company has proactively assessed every manager. Further detail on this assessment, along with the assessments, was requested in DPS 3-40. In the response a more detailed description was provided of the assessments, but no actual assessments were provided. Ultimately, it was agreed that a sample of assessments would be provided on-site. While on-site a random sample of five employees' assessments was reviewed and it was apparent that the managers actually did a self-evaluation for their supervisor to approve. With incentive compensation on the line you have to wonder how objective the self evaluations truly were.

Q. WHAT DID YOU MEAN THAT MANAGEMENT ACTIONS AND/OR PERFORMANCE HAS NOT INSTILLED CONFIDENCE IN THE EMPLOYEES OF CVPS?

A. The Company does an annual survey of its employees, which is a very good way to assess management. Copies of those surveys were provided in response to DPS 3-26. Some of the questions and the percentage of favorable responses is as follows:

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Based on the findings, of which only some were provided here, there are some serious problems internally. A concern also exists as to why unfavorable topics were deleted in 2003. It is worth noting that the customer service studies provided show a more favorable rating.

Q. SHOULD THE POOR EMPLOYEE SURVEY RESULTS BE A REAL CONCERN?

A. Yes. The opinions of the employee is a reflection of what is happening within the Company. The management of CVPS has taken notice of some of these results as evidenced by the low ratings being addressed in the Board of Director's meeting minutes.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE FURTHER ASSESSMENT AND/OR REVIEW OF MANAGEMENT?

A. The implementation of SOX has companies taking a good look at what is going on within. Since management is having to accept direct and formal responsibility for the activities of the Company a number of changes are being made including the up dating of various policy and procedure manuals. The evaluation of internal controls by the Company's outside auditor is the first step that must be completed. Assuming a favorable opinion is received in 2004, then the Board may want to consider a limited review of the effectiveness of management (officers specifically) on the operations and maintenance activities of the Company. This would be similar to the 1998 review that focused on capital budgeting, Board of Directors and corporate ethics. Delaying the review will also provide the opportunity to see how the employee concerns identified on the Board of Director minutes have been addressed by management.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.